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THE CERI ENERGY PRICING AND DEMAND MODELS: A DESCRIPTION AND INTERNAL EVALUATION

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PREFACE

This volume contains a description of a set of energy pricing and demand models developed by CERI over the past few years. The description and analysis herein concentrate on the economic content of the models. Technical detail required to use the models is available from CERI.

The models have been developed in stages and were designed for specific purposes. The energy demand models (CREED) were originally constructed by Gordon W. Douglas. Recent enhancements to CREED have been a team effort of Gordon W. Douglas, Leonard A. Coad, and Brian W. Cox. The oil and gas pricing model (COGPRICE) has been developed by Douglas J. Haughey. Valuable insights and comments from a number of CERI staff have helped improve the models.

EXECUTIVE SUMMARY

This paper presents a description and evaluation of a set of Canadian energy demand and pricing models. The models have been developed over the past three years as part of CERI's energy research program.

The Canadian Regional Energy Demand (CREED) models employ an econometrically estimated top-down framework to forecast energy demands on a regional basis. Within each region, residential, commercial, industrial, feedstock, transportation, and producer consumption are modelled. Within the residential, commercial, and industrial sectors, market shares, for oil, natural gas and electricity are econometrically modelled on the basis of relative prices. A weighted average energy price is then combined with other economic and weather variables to determine energy demand for that sector.

Sectoral fuel demands are aggregated to regional demands which are aggregated to national demands. These demands for oil and natural gas are transferred to the Canadian Oil and Gas Price (COGPRICE) model. COGPRICE determines regional burner-tip prices for heavy and light fuel oil and for natural gas as well as wellhead prices for oil and gas. The impacts of policy or legislation are fully reflected along with domestic and export demands. Electricity prices are input exogenously.

A brief internal evaluation of the strengths and weaknesses of each model is also presented. The purpose of the evaluation is to give potential users some indication of the intended uses of the models and of their potential for future development.

Finally, a sample forecast is presented to illustrate the properties of the models. The results of a set of price impacts are also presented to illustrate the response of forecast demands to changing relative prices. Further details concerning model outputs or mechanics can be found in the "CERI Energy Modelling System User's Guide" or by contacting the Institute.

1. INTRODUCTION

The CERI energy pricing and demand models are a set of microcomputer based tools for forecasting long-run trends in Canadian energy prices and demands. The focus of the models is on prices for oil, oil products, natural gas, and electricity, and on oil, gas and electricity demands in the residential, commercial, and industrial sectors. Non-energy, pipeline, and transportation use are also modelled. The models have evolved over the past three years as part of CERI's ongoing program of energy research.

The modelling system includes a national oil and gas pricing model and seven regional energy demand models. The models were originally developed on mainframe computers, then transferred to a microcomputer. The modelling system is written in IFPS/PERSONAL (Interactive Financial Planning System), a high-level, user friendly computer language.

The Canadian Regional Energy Demand (CREED) models forecast demands for oil products, natural gas, and electricity by end-use sector by region. Each regional model contains 150 to 175 variables. The regions included are the Atlantic, Quebec, Ontario, Manitoba, Saskatchewan, Alberta, and British Columbia.

The Canadian Oil and Gas Price (COGPRICE) model examines the impacts on burner-tip and wellhead prices of oil products and natural gas of changes in world oil prices, domestic legislation, and domestic or export demands. COGPRICE contains approximately three hundred variables and presents burner-tip prices by region and by sector. The main purpose of COGPRICE is to provide the price feedback loop in the regional demand models.

All models are based on public domain data. Sources and mechanical details related to model operation are documented in a user's manual. This paper concentrates on the economic content of the models and also presents CERI's internal evaluation of the system.

The modelling system described in this report should be viewed as a long-run price and demand forecasting tool. The models are suitable for policy analysis within that context. The real strength of many forecasting models is their ability to assess impacts. From a

base case which may or may not be a "true" forecast, the impacts of legislation, external events, etc. may be evaluated with a reasonable level of accuracy.

COGPRICE and CREED view energy supply as exogeneous inputs so that these models are not intended to forecast any kind of equilibrium. It is the user's responsibility to ensure that all exogeneous macro-economic, pricing, and supply assumptions are consistent. A more complete evaluation of each model's intended uses as well as its strengths and weaknesses is included in the following sections.

The CERI energy modelling system presented herein has evolved through a number of stages. Given various constraints, it was not considered optimal to spend a great deal of time revising and optimizing code. As factors such as pricing legislation change, the model code must be updated. As time passes, this can result in fragmented or redundant code. Also, a number of structural enhancements have not been undertaken, because of lack of funding. The models are therefore not presented as the best possible, but only as useful tools that improve in some ways on previous efforts.

2. CANADIAN REGIONAL ENERGY DEMAND MODEL

2.1 Overview

The Canadian Regional Energy Demand Model (CREED) uses a top-down econometric formulation to project future demands for natural gas, oil products, and electricity. These demands are forecast for the residential, commercial, and industrial sectors in seven regions. Feedstock, non-energy, transportation, and producer consumption uses are also forecast by region. An overview is presented in Figure 2.1.

The top-down approach means that fuel demands are estimated by first estimating total energy demand and fuel market shares. Individual fuel demands are calculated as the product of total energy demand and market share. Econometric estimation of the behavioural equations implies that future energy demands will be influenced by the same set of factors that influenced demands over the sample period.

Once individual fuel demands have been calculated by sector for each region, they are aggregated into total regional demands. These regional demands are further aggregated into national demands which are transferred to COGPRICE.

2.2 Model Specification

The regional sub-models of CREED (with the exception of the Ontario industrial sector) are all specified in the same manner. Each sector is treated as a recursive, partial adjustment model (see Figure 2.2).[1] Market shares for electricity, oil, and natural gas are estimated on the basis of relative prices, and are used to calculate a weighted average energy price. This price, together with other demographic, weather, and economic activity variables, is used to estimate sectoral energy demand. Individual fuel demands are the product of sectoral energy demand and market shares.

A lagged dependent variable is included in each estimated equation. Due to the durable nature of energy-using capital stock, the actual level and mix of energy use cannot adjust immediately to desired levels. The lagged dependent variable is intended to capture this effect.

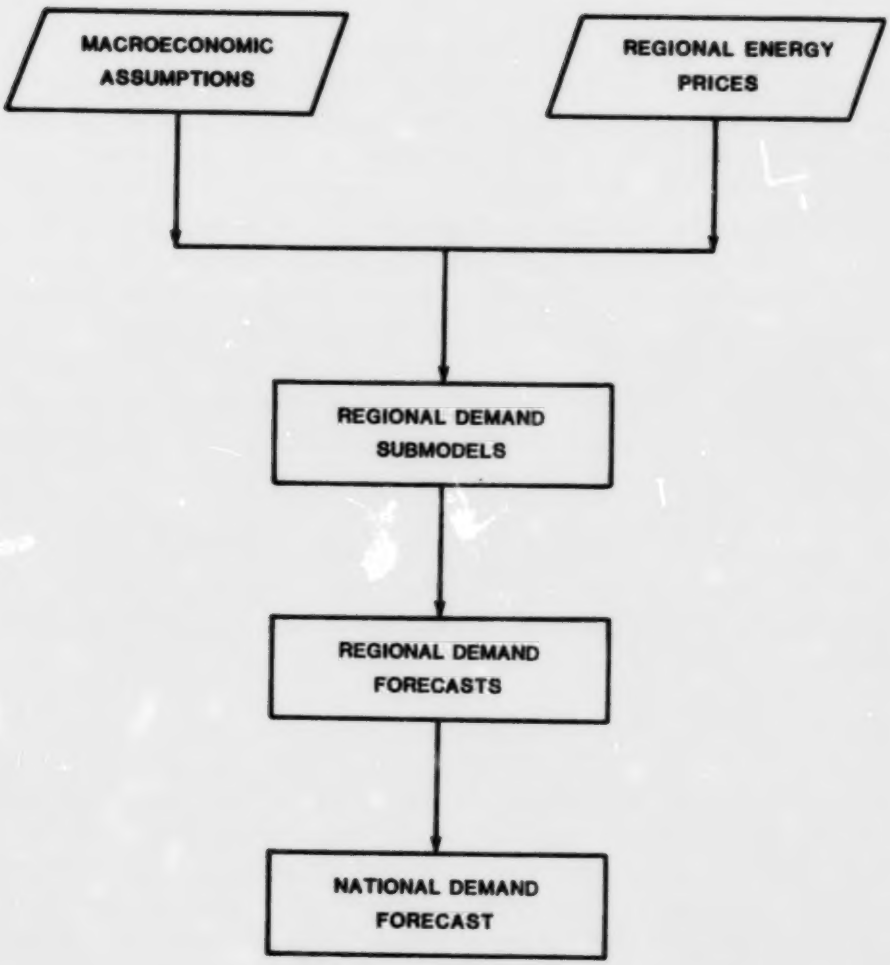


FIGURE 2.1: OVERVIEW OF CREED

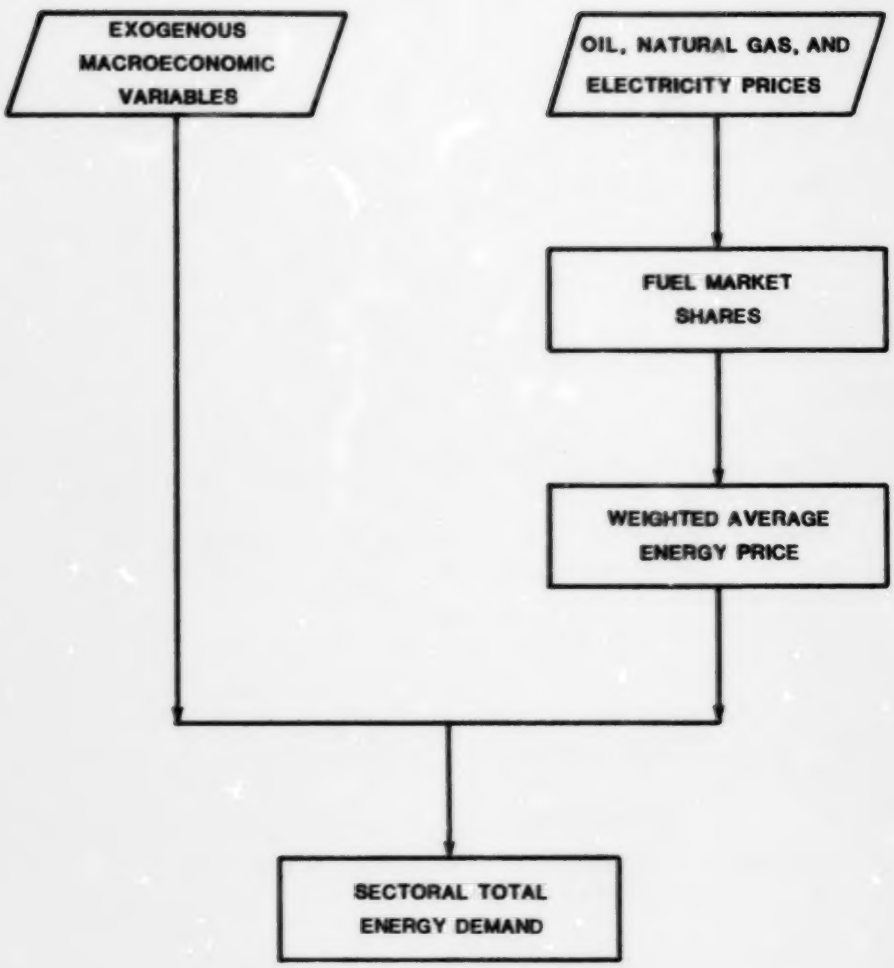

EXOGENOUS MACROECONOMIC VARIABLES
OIL, NATURAL GAS, AND ELECTRICITY PRICES
FUEL MARKET SHARES
WEIGHTED AVERAGE ENERGY PRICE
SECTORAL TOTAL ENERGY DEMAND

FIGURE 2.2: SECTORAL DEMAND SUBMODELS

Algebraically, the demand model formulation can be represented for a given sector and region in year t as:

$$MS_{it} = f(MS_{it-1}, P_{1t}, P_{2t}, P_{3t}): \; i = 1, 2, 3$$

$$PE_t = \sum_{i=1}^{3} MS_{it} \times P_{it}$$

$$TE_t = f(TE_{t-1}, PE_t, X_t, R_t)$$

$$C_{it} = MS_{it} \times TE_t : \; i = 1, 2, 3$$

where:

MS_{it} = market share of fuel i in year t

P_{it} = price of fuel i in year t (measured in equivalent units)

PE_t = overall energy average price in year t

TE_t = total energy consumption in year t (sum of consumption of the three fuels)

X_t = a series of exogenous economic, demographic, weather-related and other variables in year t

R_t = regional dummy variables for year t

C_{it} = consumption of fuel type i in year t

The model described above is similar to the Interfuel Substitution Demand Model (IFSDM) of EMR.[2] However, a major difference is in the specification of energy demand units; CREED is modelled on the basis of "input" Btu units whereas IFSDM uses "output" Btu units. Input energy units represent the heat content of a fuel as it enters an energy-using appliance or process. Output energy units measure the useful energy produced by the appliance or process. The output measure

will always be smaller than the input measure, with the difference referred to as conversion loss and the ratio of output energy to input energy referred to as conversion efficiency.

The choice of input Btu units is intended to provide more accurate long-term energy price coefficients. When output units are used, the effects on energy demand of changes in the energy efficiency of capital are difficult to capture. Because the price is measured in output units, its coefficient does not capture these effects. One is also faced with the necessity of measuring the changes in conversion efficiencies (for which data are not generally available), or one must ignore the effect entirely by imposing a constant conversion efficiency. The use of input units allows the price coefficient to capture the full effect of price changes on long-run energy demand.[3]

The choice of input units can be criticized on the grounds that, where conversion efficiencies change through time, it interferes with the symmetry of cross-price effects on the market share equations. Also, when relative prices change a problem of aggregation is introduced into the total energy equation. The problem is that equivalent changes in relative prices have different effects depending on which fuel changes in price. Empirically, there does not appear to be clear evidence for choosing one method over the other. Input units are chosen here for their ability to capture the effects of changes in efficiency of the capital stock.

The total energy and market share equations are estimated on the basis of three fuels only (electricity, natural gas, and oil products). In the residential sector, oil products refers to distillates (light fuel oil and kerosene), whereas in the commercial and industrial sectors oil products refers to heavy fuel oil.

The specification of the fuel price variables in the total energy and market share equations was determined by data availability in the EMR database (see Section 2.3). The natural gas and oil products prices are average prices for each sector. In the residential sector, the electricity price is a "marginal" or end block price whereas the electricity prices used for the commercial and industrial sectors are essentially average prices.

Each total energy demand equation is specified in logarithmic form. For the residential sector, energy demand per household is a function of energy price, real personal disposable income per household, weather and a lagged dependent variable. Energy demand per

household (the decision making unit) was modelled in order to better isolate the impacts of energy prices and incomes on demand. The number of households acts as a scale factor so that total energy consumption varies directly with the number of households.

Commercial sector total demand (excluding street lighting) was specified as a function of energy price, commercial real domestic product (RDP), weather and a lagged dependent variable.

Electricity serves a captive market for street lighting. Street lighting electricity demand is specified as a function of electricity price, commercial real domestic product, and a lagged dependent variable.

The industrial sector is modelled somewhat differently. The assumption of interfuel substitution between electricity and fossil fuels is suspended. This is based, in part, on preliminary econometric results and is not unprecedented. Over the estimation period (1963-1979), there was little to no dual-fired gas/electric or oil/electric capability for industrial boilers in Canada. One would expect less substitution potential between energy forms in this sector due to the fuel-specific nature of much of the capital stock. Therefore, demand for the two fossil fuels--natural gas plus heavy fuel oil--is estimated separately from electricity. The specification for each equation is similar in that demand is a function of the appropriate energy price, industrial real domestic product, and the industrial capital-output ratio. For the heavy fuel oil and natural gas equations a lagged dependent variable was included. A lagged dependent variable term was not used in the industrial electricity equation because such an approach produced unsatisfactory results.

Each market share equation is specified in semi-logarithmic form. The residential and commercial market share equations are specified as a function of the three fuel prices (electricity, natural gas and oil products) and the lagged dependent variable. The industrial market share equation is specified as a function of two fuel prices (natural gas and heavy fuel oil) and the lagged dependent variable.

Several constraints consistent with economic theory are imposed on the market share equations, namely:

- The market share of each fuel should remain unchanged when all fuel prices change by the same proportion (i.e., there is homogeneity of degree zero in prices). This is satisfied if the sum of the price coefficients is zero.

- Coefficients were restricted such that price changes had symmetrical effects, i.e., the change in market share of one fuel with respect to a percentage change in the price of another fuel is equal to the change in the market share of the other fuel with respect to the same percentage change in the price of the first fuel.

These two conditions ensure that, if the market shares sum to one before any changes in price, they will continue to sum to one after any price change.

A third restriction is imposed. To ensure that any change in the market share of one fuel is exactly offset by changes in the market shares of the other fuels in every time period, we set the coefficient of the lagged dependent variable equal for each fuel share.

CREED also includes equations to project transportation, feedstock, and producer consumption for oil products and natural gas and producer consumption of electricity. In each case, the equation uses an initial value as a scale factor. This value is multiplied by a series of price and activity variables (each with its own elasticity) to arrive at a demand projection. These equations are based on preliminary econometric results only and could be enhanced in the future.

2.3 The Database and Estimation Procedure

The IFSDM database has been the primary data source employed, but supplemental data from the National Energy Board, the Conference Board of Canada and Statistics Canada also have been used.

The IFSDM database encompasses data for seven regions--Atlantic Canada, Quebec, Ontario, Manitoba, Saskatchewan, Alberta, and British Columbia and the Territories. A pooled "cross-section time-series" approach was adopted for estimating total energy demand and market share model coefficients. Model coefficients were estimated using data over the 1963-1979 period, i.e., a total of 119 observations. Regional intercepts were introduced into the energy demand equations. The approach adopted allows one to exploit interregional variation in fuel prices which aids the statistical estimation of the relationships. One

disadvantage to the approach is that the model may not track the variation over time within particular regions very acurately.

The parameters of the total energy equations were estimated (after natural logarithmic transformation) using an ordinary least squares regression technique. Due to the presence of parameter restrictions, the parameters of the market share equations were estimated using Zellner's restricted least squares regression method.[4]

2.4 Econometric Results

Total energy demand and market share equation results are reported in Tables 2.1 and 2.2, respectively. Generally, coefficients of the activity variables (overall energy price, income/output and weather as measured by degree days) of the energy demand equations exhibit the correct signs, plausible magnitudes and are statistically significant. In the market share equation results, the coefficients of the price terms for each fuel demonstrate the theoretically correct signs for own and cross-price elasticities. Many, however, are statistically insignificant.

Within each sector, the market share parameters are estimated simultaneously as a system of equations imposing the parameter restrictions indicated previously. Each system involves n equations with n being one less than the number of fuels considered. The market share of the remaining fuel is determined as a residual. A dummy variable was included for the Quebec/Atlantic region in the commercial market share equations due to the small natural gas distribution system in these areas. Because of the high market share of natural gas used in the industrial sectors of Alberta and Saskatchewan and the low natural gas industrial market share in the Atlantic region, data from these three regions were excluded from the estimation of the industrial market share equations, (i.e., the model coefficients were estimated over 68 observations rather than 119 observations). In regions for which industrial market shares are not estimated, shares are imposed exogenously.

The coefficients of the lagged dependent variable terms in the total energy equations are in the range 0.56 to 0.88 indicating that between 12 and 44 percent of the adjustment to the desired demand level occurs in the first year.[5] In contrast, the coefficient of the lagged dependent variables in the market share equations ranged from

TABLE 2.1

TOTAL ENERGY DEMAND EQUATION COEFFICIENTS, LOGARITHMIC FORM, 1963-1979[a]

Independent Variables	Units	Residential	Commercial	Street Lighting	Industrial	Industrial
		Total Energy/ Household (10^9Btu)	Total Energy (10^{12}Btu)	Electricity (10^{12}Btu)	Oil Plus Gas (10^{12}Btu)	Electricity (10^{12}Btu)
Intercept		-0.05975	-3.2238	-0.83737	0.87303	1.4478
		(0.43)	(4.79)	(1.79)	(4.55)	(17.15)
Atl Dummy	0-1	0.10155	0.06960	0.01865	0.09954	1.0299
		(3.50)	(1.62)	(1.05)	(1.63)	(15.13)
Que Dummy	0-1	0.04265	-0.12918	0.08976	-0.00590	0.04909
		(2.41)	(2.43)	(4.54)	(0.09)	(0.66)
Ont Dummy	0-1	0.05532	-0.13308	0.04623	-0.07897	-0.65781
		(2.91)	(1.91)	(1.75)	(0.86)	(6.52)
Man Dummy	0-1	0.03955	0.18406	0.02254	0.09666	1.1927
		(2.24)	(2.84)	(0.74)	(1.09)	(12.73)
Sas Dummy	0-1	0.07276	0.16741	-0.02410	0.48588	1.2341
		(3.24)	(2.31)	(1.04)	(3.44)	(11.03)
Alt Dummy	0-1	0.01322	0.18997	0.06239	0.14505	-0.12968
		(0.58)	(2.87)	(2.98)	(1.59)	(1.28)
Lagged Dependent		0.74870	0.55532	0.87568	0.69213	
		(12.51)	(9.13)	(21.82)	(11.78)	
Energy Price	\$1971/10^6Btu	-0.12230	-0.27698		-0.06538	
		(4.27)	(5.41)		(1.73)	
Electricity Price[b]	\$1971/10^6Btu			-0.08876		-0.14699
				(2.33)		(3.09)
Real PDI/Household	10^3 \$1971	0.08809				
		(2.08)				
Degree Days Index		0.58507	0.45558			
		(7.62)	(2.55)			
Lagged Degree Days Index		-0.48291	-0.43743			
		(5.84)	(2.41)			
Industrial RDP	10^9 \$1971				0.37850	1.4902
					(4.27)	(24.65)
Capital/Output Ratio	None				0.27238	0.49999
					(2.46)	(4.41)
Commercial RDP	10^6 \$1971		0.59512	0.09124		
			(5.72)	(1.79)		
$\bar{R}^2$		0.923	0.990	0.998	0.986	0.983
Sample Size[c]		119	119	119	119	119

[a] T-values in brackets.
[b] For street lighting, this is an index with 1971 = 1.0 for each region.
[c] 17 years times 7 regions.

TABLE 2.2

MARKET SHARE EQUATION COEFFICIENTS,
1963-1979[a]

Independent Variables	Unit	Dependent Variable	
		Electricity Market Share	Natural Gas Market Share
Residential:			
Intercept		0.02609	0.00697
		(6.09)	(2.40)
Lagged Dependent		0.98727	0.98727
		(133.41)	(133.41)
Electricity Price[b]	$1971/10^6$Btu	-0.01645	0.00342
		(4.39)	(1.89)
Natural Gas Price[b]	$1971/10^6$Btu	0.00342	-0.00846
		(1.89)	(2.18)
Light Fuel Oil Price[b]	$1971/10^6$Btu	0.01304	0.00505
		(4.04)	(1.40)
$\bar{R}^2$		0.978	0.998
Sample Size[e]		119	119
Commercial:			
Intercept		0.05057	0.05058
		(2.53)	(3.59)
Lagged Dependent		0.92371	0.92371
		(40.30)	(40.30)
Electricity Price[b]	$1971/10^6$Btu	-0.01474	0.00294
		(1.58)	(0.43)
Natural Gas Price[b]	$1971/10^6$Btu	0.00294	-0.00873
		(0.43)	(0.87)
Heavy Fuel Oil Price[b]	$1971/10^6$Btu	0.01180	0.00579
		(1.57)	(0.79)
Atl/Que Dummy	0-1	0.01800	-0.04314
		(2.23)	(3.91)
$\bar{R}^2$		0.893	0.990
Sample Size[e]		119	119
Industrial:[c,d]			
Intercept			0.02083
			(1.15)
Lagged Dependent			0.98377
			(28.95)
Natural Gas Price[b]	$1971/10^6$Btu		-0.00162
			(0.07)
Heavy Fuel Oil Price[b]	$1971/10^6$Btu		0.00162
			(0.07)
$\bar{R}^2$			0.960
Sample Size[e]			68

[a] T-values in brackets.
[b] Natural logarithmic form.
[c] Estimated excluding Alberta and Saskatchewan data due to the high market share of gas in this region and excluding the Atlantic region because of the low gas market share in this region.
[d] For industrial the gas market share is the share of gas plus oil demand only.
[e] 17 years times number of regions.

0.92 to 0.99 indicating very slow adjustment in market shares to changing relative fuel prices. One expects this. The decision to alter the level of energy consumption will be made more quickly than a decision to switch fuels. The latter often involves the purchase of new capital equipment and this decision is made only when relative price changes are perceived as permanent and the capital purchase can be cost justified.

2.5 The Ontario Industrial Sector

This section presents the results of CERI's most recent enhancements to CREED. The model as outlined above can be improved in several directions. The Ontario industrial sector was selected for improvement because of its relative importance in terms of total energy demand in Canada and because of the current importance of interfuel competition in that sector.

The model structure for the Ontario industrial sector was modified in three important ways. First, region-specific data were used. The use of pooled regional and time series data (as in the rest of the model) gives equations that are more accurate for Canada as a whole than for a specific region. Estimating Ontario individually should improve results for that region.

The second modification was to model total energy and market shares on the basis of three fuels rather than two. This permits the resulting model to examine the issue of competition between natural gas and fuel oil relative to electricity in the Ontario industrial sector.

The third modification was to drop the lagged dependent variable from the estimated equations. The presence of a lagged dependent variable adds considerable inertia to an equation. Equations with a lagged dependent variable tend to react slowly to a change in exogenous variables, but they also tend to over-react in the long run.

Without a lagged dependent variable, the long-term response to energy price changes must be modelled explicitly. Price lags were introduced into the total energy and market share equations to capture the long-term adjustment of demands to price changes.

In the total energy equation a ten-year distributed lag was imposed on the average price of energy. One might argue that a longer lag is appropriate, although data availability severely hampers any

attempt to impose a longer lag. A number of lag structures were attempted, with shorter lags giving better results than longer lags. The final choice of lag structure was based on statistical results and economic insights. For the total energy equation, data were obtained from 1955-1982. Price data for 1955-1958 were estimated due to lack of available data.

Market share equations in the industrial sector of Ontario include a unique lag structure which in part reflects the dynamics of fuel switching choices. The equation for electricity market share imposes a five-year distributed lag on all three prices. The natural gas equation imposes a five-year lag on the electricity price and uses the current price for natural gas and heavy fuel oil. This immediate effect on the natural gas share of prices of natural gas and fuel oil reflects the potential of dual-fuel capable capital stock to switch fuels quickly. The longer lags on the electricity price in the natural gas equation and on all prices in the electricity equation indicate that fuel switching involving electricity occurs more slowly. In part, this is due to the expense of replacing capital stock. This lag structure has the disadvantage that it does not preserve short-run symmetry of cross-price elasticities in the natural gas equation. In turn, this means that a one-time shock in different fuel prices will have different effects on the market shares for the following four years. Such a disadvantage was considered small relative to the advantage of a more realistic representation of current market dynamics.

The industrial market share of coal is included in the market share equations as an exogenous explanatory variable. Although data and other limitations did not permit modelling coal as an endogenous share, its importance cannot be overlooked. Over the 1962-1982 sample period, coal lost industrial load rapidly to natural gas, electricity, and fuel oil (in order of importance). As the market share of coal (based on four fuels) fell from 37 percent in 1962 to only 4 percent in 1982, the largest portion switched to natural gas. This means that the three-fuel market share of natural gas rose due to the decline in coal use (i.e., coal load shifted more to gas than to other fuels, increasing the gas share). This effect explains the inverse relationship between coal market share and natural gas market share and the proportional relationship with other fuels.

The estimated results for the Ontario industrial sector are presented in Table 2.3. All coefficients take the appropriate sign and have plausible magnitudes, and most are statistically significant. The

TABLE 2.3

ONTARIO INDUSTRIAL SECTOR COEFFICIENTS
MARKET SHARE EQUATIONS
(1962-1982)

Independent Variables	Unit	Dependent Variable	
		Electricity Market Share	Natural Gas Market Share
Intercept		0.31062	0.57310
		(11.24)	(46.41)
Electricity Price	$1971/10^6Btu	-0.074771	0.050372
		(2.47)	(3.00)
Natural Gas Price	$1971/10^6Btu	0.050372	-0.058978
		(3.00)	(-3.64)
Heavy Fuel Oil Price	$1971/10^6Btu	0.024399	0.008606
		(0.75)	(0.75)
Industrial Market Share of Coal		0.27117	-0.70118
		(3.44)	(-13.63)
Dummy Variable 1977		-0.027449	-0.043144
		(-1.25)	(-3.27)
$\bar{R}^2$		0.5293	0.9534
System R^2 = .9809			

Total Energy Equation

Independent Variable	Unit	Coefficient	T-Ratio
Intercept		-1.3797	-0.71
Distributed Lag Average Energy Price	$1971/10^6Btu	-0.95242	-12.62
Ratio of current IRDP to previous peak		1.0976	2.68
Capital Stock	Millions $1971	0.88877	22.46
$\bar{R}^2$ = .9775			

tendency of heavy fuel oil and natural gas prices to move together over the sample period makes it difficult to get a good separation of the effects of the two prices in the market share equations. The absence of the lagged dependent variable in the market share equations leads to much larger price coefficients.

The total energy equation reflects the trend toward more energy-efficient capital stock. It also shows that holding capital stock constant and increasing the level of RDP (thereby increasing capacity utilization) increases energy demand more than proportionately. This is consistent with a belief that if capital must be left idle, the least energy-efficient capital will be retired.

2.6 Key Relationships

Because of the econometric nature of CREED and its simple structure, the key relationships are easily identified. The market share equations in each sector and each region are influenced exclusively by relative fuel prices. The total energy equations are also affected by average fuel prices and by a small number of exogenous factors.

In the residential sector, total energy demand is influenced by prices, real disposable income per household, and degree days. It is important to remember that real personal disposable income and households are entered separately, and it is their ratio that enters the total energy equation. Consistency between the income and households forecasts is essential in forecasting total residential energy.

In the commercial sector, energy prices, weather, and commercial sector RDP drive total energy demand. Commercial RDP is determined as a share of total RDP. This allows the commercial and industrial sectors to grow at different rates but requires their shares to be consistent (Note that agriculture and fishing are not included in sectoral RDP so that commercial plus industrial shares sum to less than unity).

Industrial sector total energy demand (except in Ontario) is determined by average energy prices, the capital/output ratio, and industrial sector RDP.

The presence of lagged dependent variables introduces a time trend influence in the behavioural equations of CREED. Because of the

lagged dependent variable, a shock in any of the explanatory variables is felt through time. The length of time required for the total effect depends entirely on the coefficient of the lagged dependent variable. In the Ontario industrial sector there are no lagged dependent variables. Energy prices will continue to have a lagged effect because they are distributed lag variables. However, RDP shocks are felt entirely within the year they occur.

2.7 Tracking Properties

Two sample period simulations were performed to examine the ability of the estimated equations to track historical data. The simulation process is dynamic in that errors in one equation are permitted to feed through other equations as well as over time. This type of simulation provides an extremely rigorous test of the equations. The test is particularly difficult over the 1970s when energy markets were in a constant state of upheaval.

The model was used to predict total energy demand for Canada as a whole over the 1963-1979 period. The results of this simulation (see Figure 2.3) show that the model tracks total energy demand very well.

A second simulation was performed using the equations estimated for the Ontario industrial sector. This simulation was performed over the 1966-1982 period, the period over which the model was estimated. Figures 2.4 and 2.5 present the results for total industrial energy demand and individual fuel demands, respectively. The average absolute percentage error (AAPE) statistics show that it is somewhat more difficult to get accurate predictions for the Ontario industrial sector specifically than for Canada as a whole.

2.8 Forecasting Properties

The forecasting properties of the model were examined by developing the reference case described in Section 4 as a base, and then shocking prices and examining the impact on total energy and market shares. In each case, burner-tip prices were increased by 10 percent in 1984, then allowed to continue their previous growth pattern from the new level. The prices of natural gas, electricity, and fuel oil were shocked individually, then together. Calculated elasticities are presented in Table 2.4 for Canada as a whole and in Table 2.5 for the Ontario industrial sector. In all cases the own-price elasticities are negative and less than unity in absolute value, indicating inelastic

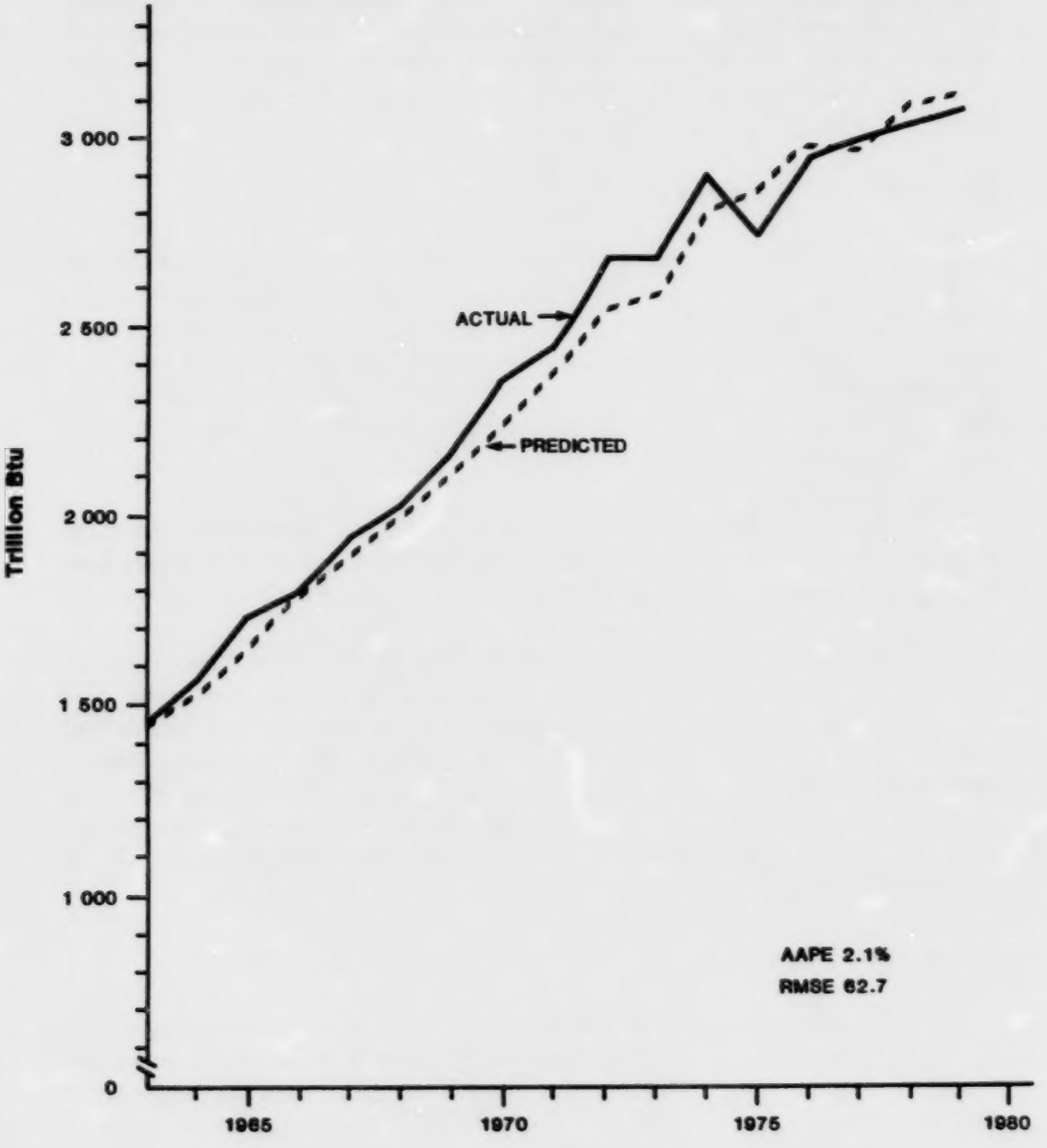


FIGURE 2.3: MODEL TRACKING PROPERTIES: TOTAL ENERGY DEMAND - CANADA

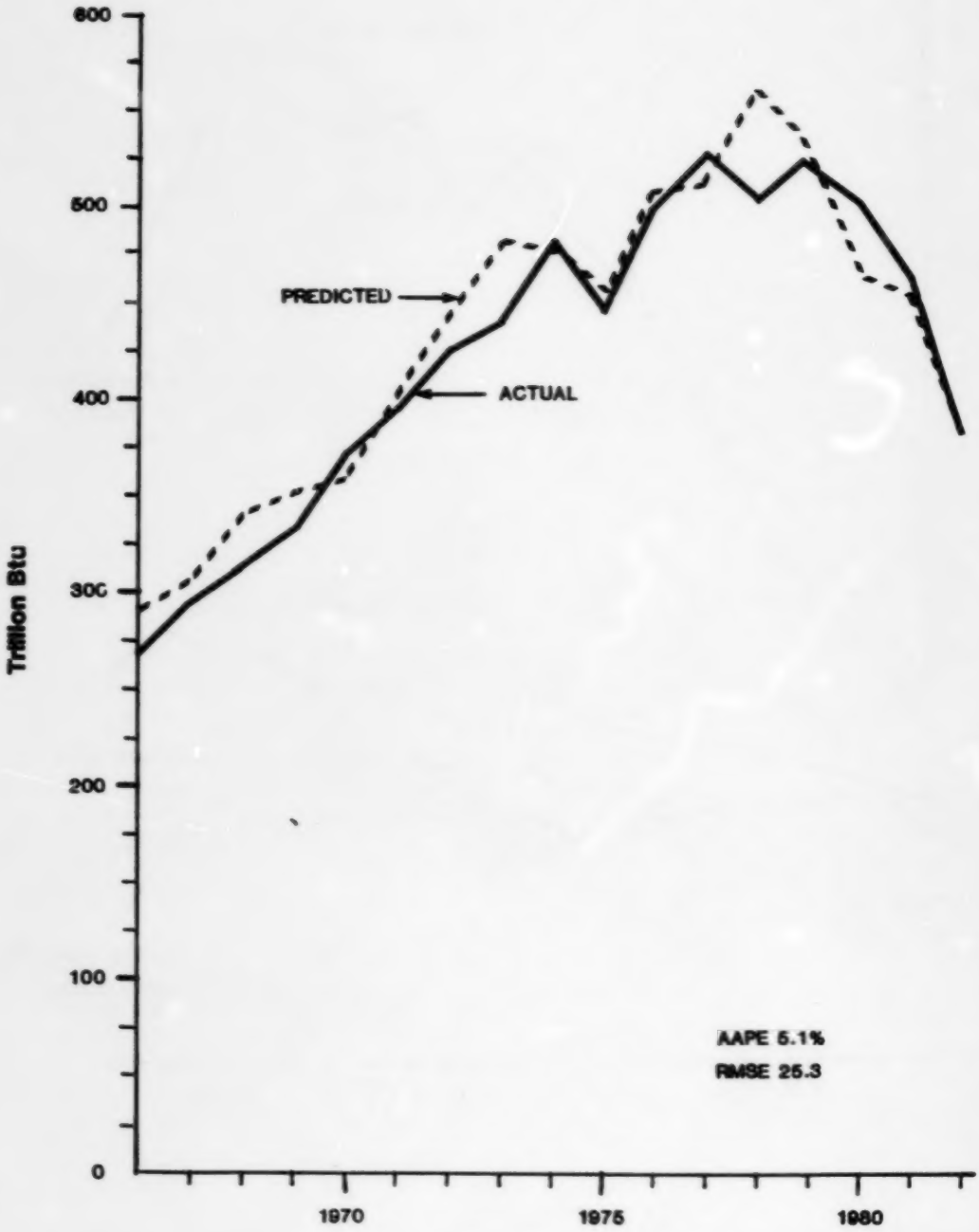


FIGURE 2.4: MODEL TRACKING PROPERTIES: TOTAL ENERGY DEMAND - ONTARIO INDUSTRIAL SECTOR

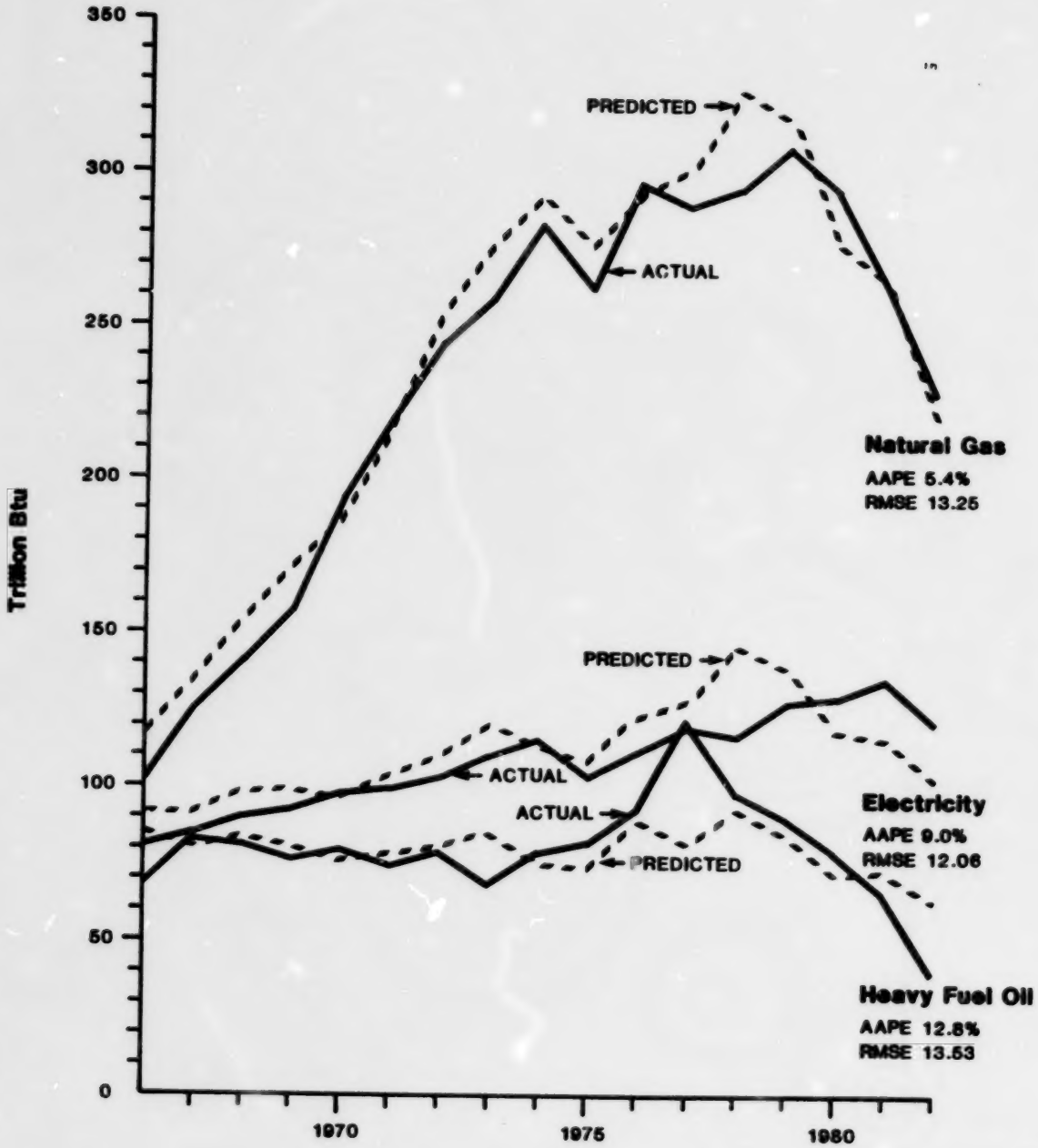


FIGURE 2.5: MODEL TRACKING PROPERTIES: INDIVIDUAL FUELS DEMAND - ONTARIO INDUSTRIAL SECTOR

TABLE 2.4

PRICE ELASTICITIES - CANADA TOTAL

Fuel Type	Demand Impact of a 1 Percent Price Increase Of: All Fuels	Electricity	Natural Gas	Oil
SHORT-TERM (1 Year)				
All Fuels	-0.18	-0.05	-0.03	-0.10
Electricity	-0.14	-0.12	-0.02	-0.01
Natural Gas	-0.15	-0.05	-0.10	-0.003
Oil	-0.21	-0.01	0.01	-0.20
MEDIUM-TERM (6 Years)				
All Fuels	-0.32	-0.12	-0.11	-0.13
Electricity	-0.39	-0.34	-0.07	0.003
Natural Gas	-0.39	-0.14	-0.28	0.003
Oil	-0.31	0.00	-0.02	-0.27
LONG-TERM (11 Years)				
All Fuels	-0.38	-0.13	-0.14	-0.13
Electricity	-0.43	-0.42	-0.04	0.03
Natural Gas	-0.43	-0.12	-0.34	0.02
Oil	-0.31	0.03	-0.01	-0.31

NOTE: Negative cross-price elasticities indicate that the effect of price-induced conservation on total energy demand outweighs the fuel switching effect of higher prices on market shares.

TABLE 2.5

PRICE ELASTICITIES - ONTARIO INDUSTRIAL SECTOR

Fuel Type	Demand Impact of a 1 Percent Price Increase Of: All Fuels	Electricity	Natural Gas	Oil
SHORT-TERM (1 Year)				
All Fuels	-0.06	-0.03	-0.03	-0.01
Electricity	-0.06	-0.04	-0.02	-0.002
Natural Gas	-0.14	-0.02	-0.13	0.01
Oil	0.42	-0.02	0.54	-0.11
MEDIUM-TERM (6 Years)				
All Fuels	-0.72	-0.30	-0.36	-0.08
Electricity	-0.71	-0.50	-0.23	-0.01
Natural Gas	-0.72	-0.23	-0.45	-0.06
Oil	-0.73	-0.05	-0.25	-0.45
LONG-TERM (11 Years)				
All Fuels	-0.87	-0.36	-0.45	-0.09
Electricity	-0.86	-0.55	-0.34	-0.03
Natural Gas	-0.87	-0.28	-0.54	-0.08
Oil	-0.87	-0.10	-0.32	-0.48

NOTE: Negative cross-price elasticities indicate that the effect of price-induced conservation on total energy demand outweighs the fuel switching effect of higher prices on market shares.

demands. The own-price elasticities for the Ontario industrial sector are generally larger than for the rest of the model.

Many of cross-price elasticities are negative for both Canadian total energy and Ontario industrial energy demand. These elasticities can be divided into two components, namely a total energy effect and a substitution effect. For an increase in any price, total energy demand should decrease, yielding a negative total energy component in the elasticity. The substitution effect is felt through the market share equations. When the price of another fuel rises relative to a given fuel, the substitution component is positive. The cross-price elasticity represents the net effect of total energy and substitution and its sign depends on the relative magnitudes of the two components. A negative cross-price elasticity implies that the decrease due to the total energy effect outweighs the increase due to substitution.

Table 2.6 shows the substitution effect on market shares in the Ontario industrial sector. The impact on market shares of a given price increase is to decrease market share for the fuel whose price increases and increase market share for the other fuels. It is interesting to note the relative magnitudes of the cross-price elasticities for each fuel, particularly in the long run. These magnitudes suggest that in the long run, oil price increases cause oil to lose more share to electricity than to natural gas. This could reflect the historical tendency of natural gas and fuel oil prices to move together, making it difficult to separate their effects.

2.9 Strengths

The following factors make CREED a useful, cost-effective tool for forecasting Canadian energy demand:

- CREED provides a consistent, integrated regional forecast of energy demand,
- the model provides sectoral detail on a region-by-region basis,
- the model, when used with COGPRICE, allows feedback between demands and prices,
- the simple, recursive structure and modest exogenous data requirements make CREED an easy tool to use,

TABLE 2.6

MARKET SHARE ELASTICITIES - ONTARIO INDUSTRIAL SECTOR

Fuel Type	Market Share Impact of a 1 Percent Price Increase Of: Electricity	Natural Gas	Oil
SHORT-TERM (1 Year)			
Electricity	-0.05	0.03	0.02
Natural Gas	0.02	-0.57	0.08
Oil	0.01	0.54	-0.10
MEDIUM-TERM (6 Years)			
Electricity	-0.67	0.48	0.23
Natural Gas	0.46	-0.57	0.08
Oil	0.20	0.09	-0.31
LONG-TERM (11 Years)			
Electricity	-0.67	0.47	0.23
Natural Gas	0.46	-0.57	0.08
Oil	0.21	0.10	-0.31

NOTE: These numbers represent the change in market shares measured in percentage points, i.e., -0.05 indicates a loss of one half of one percent of the total market.

- CREED is based on the most consistent public domain energy database available in Canada,

- producer consumption of natural gas is based on demand volumes, and

- the user-friendly software and goal seeking capability make it possible to run policy scenarios easily on a national or regional basis.

When forecasting with an econometric model, it is important that data used to tune the historical portion of the forecast be consistent with the data used to estimate the model. The IFSD database satisfies this requirement. This feature, combined with the limited requirements for other exogenous data, makes CREED an excellent tool for generating consistent regional energy demand forecasts.

2.10 Weaknesses

The following weaknesses have been identified in CREED:

- the top-down approach to fuel switching decisions cannot fully capture the full-cycle economics involved; a combination with industry-specific bottom-up analysis is required,

- feedstock, producer consumption, and transportation uses of energy are not econometrically modelled in a sophisticated fashion,

- a number of macroeconomic variables are input separately for each region, requiring that the user ensure consistency within and across regions,

- the majority of the model is based on pooled data which does not always give good regional results,

- the presence of lagged dependent variables builds inertia into the equations and tends to compound errors in the long run,

- the model does not contain a feedback from the energy sector to the macroeconomy,

- the model could be re-estimated using another three years of data (1980-1982),

- the software makes reporting across regions awkward,

- coal is not modelled,
- the model does not forecast primary energy demand for generation of electricity (hydro and nuclear),
- the difference in structure between the Ontario industrial sector and the rest of the model requires the forecaster to run it differently and be aware of the differences in behavioural equations, and
- the negative cross-price elasticities (see section 3.8) make it difficult to examine interfuel substitution.

Several of the above weaknesses could be eliminated with further work. Others are not weaknesses in the model structure, but rather features of the model that require the user's attention. Re-estimation of the model on a regional basis, using currently available data and incorporating some form of bottom-up representation of the industrial sector might provide a superior model, but at a substantial cost.

Footnotes

[1] The partial adjustment model in linear form is:

$$Y_t - Y_{t-1} = a(Y_t^* - Y_{t-1})$$

Where: $0 < a \leq 1$
Y_t is the actual level of consumption in year t
Y_t^* is the desired level of consumption in year t
a is the adjustment parameter

The closer a is to unity the greater is the adjustment achieved in the current period (instantaneous adjustment implies a equals one). See J. Johnston, Econometric Methods, McGraw-Hill, New York, p. 300.

[2] "A Policy Model of Canadian Interfuel Substitution Demands" in Energy Policy Modelling: United States and Canadian Experiences, ed. by W. T. Ziemba, S. L. Schwartz and E. Koenigsberg (Boston: Maritinus Nijhoff, 1980), pp. 34-49. A minor difference between approaches is that we have used a simple average total energy price index rather than a Divisia price index (which is employed in IFSDM) for reasons of simplicity. Sahi and Erdman in a preliminary draft of their paper indicate that the use of the Divisia price index does not appear to result in significant differences from simpler forms of price indexes. The Divisia index has some attractive theoretical properties and discussion on its use can be found in: E. R. Berndt and D. O. Wood, "Technology, Prices and the Derived Demand for Energy," Review of Economics and Statistics, Vol. 57, pp. 259-263, 1975.

[3] The issue of input versus output Btu's has been widely debated. A recent summary of the issue is discussed in a paper by Berndt and Watkins entitled "Modelling Energy Demand: The Choice Between Input and Output Energy Measurement." Paper presented to the Third International Association of Energy Economists World Conference, Cambridge, U.K., June 1982 (referenced with permission).

[4] The econometric software package SHAZAM was used for all econometric work. See Kenneth J. White, "SHAZAM: An Econometric Computer Program Version 3.1," Social Science Computer Lab, Rice University, Houston, Texas, June 1980.

[5] One minus the coefficient of the lagged dependent variable terms equals the proportion of the adjustment to the desired demand level that occurs in the first year.

3. CANADIAN OIL AND GAS PRICING MODEL (COGPRICE)

This model was developed to aid in examining the domestic oil and gas pricing implications of changes in such factors as world oil prices, domestic oil and gas legislation, U.S. demand for Canadian natural gas, and domestic demand for oil products and natural gas. Markets for oil products and natural gas are represented at a high level of aggregation. The model projects regional burner-tip prices for natural gas and fuel oil, natural gas export prices, imported crude oil prices, and wellhead oil and gas prices.

An overview of COGPRICE is presented in Figure 3.1. The model is divided into two major sub-models, an oil pricing sub-model and a natural gas pricing sub-model. Assumptions on world oil prices and inflation are combined with demands and pricing legislation to provide exogeneous inputs to each sub-model. Domestic oil and gas demands are transferred from CREED through an iterative feedback mechanism. Export oil and gas demands are exogeneous inputs. Domestic pricing legislation is coded into the model and must be modified by the user as required. The two sub-models are described below.

3.1 Oil Pricing Submodel of COGPRICE

The oil pricing sub-model (Figure 3.2) projects burner-tip prices for light fuel oil (residential sector) and heavy fuel oil (commercial and industrial sectors). It is the growth rates of these prices that are transferred to the regional energy demand models of CREED. This sub-model also calculates domestic wellhead prices for crude oil.

Saudi Arabian crude is used for the benchmark price of imported oil. The Saudi price is adjusted by quality and sulphur differentials to reflect average imported oil characteristics F.O.B. Persian Gulf. Transport costs are added to determine a Montreal landed price of imported crude.

Conventional domestic oil is assumed to be 38° API with 0.5 percent sulphur. Conventional Old Oil Prices (COOP) follow the rules set out in the Alberta/Canada amending agreement of June 1983 as follows. If imported oil prices rise, COOP will only rise to maintain a price that is 75 percent of world levels. If imported oil prices

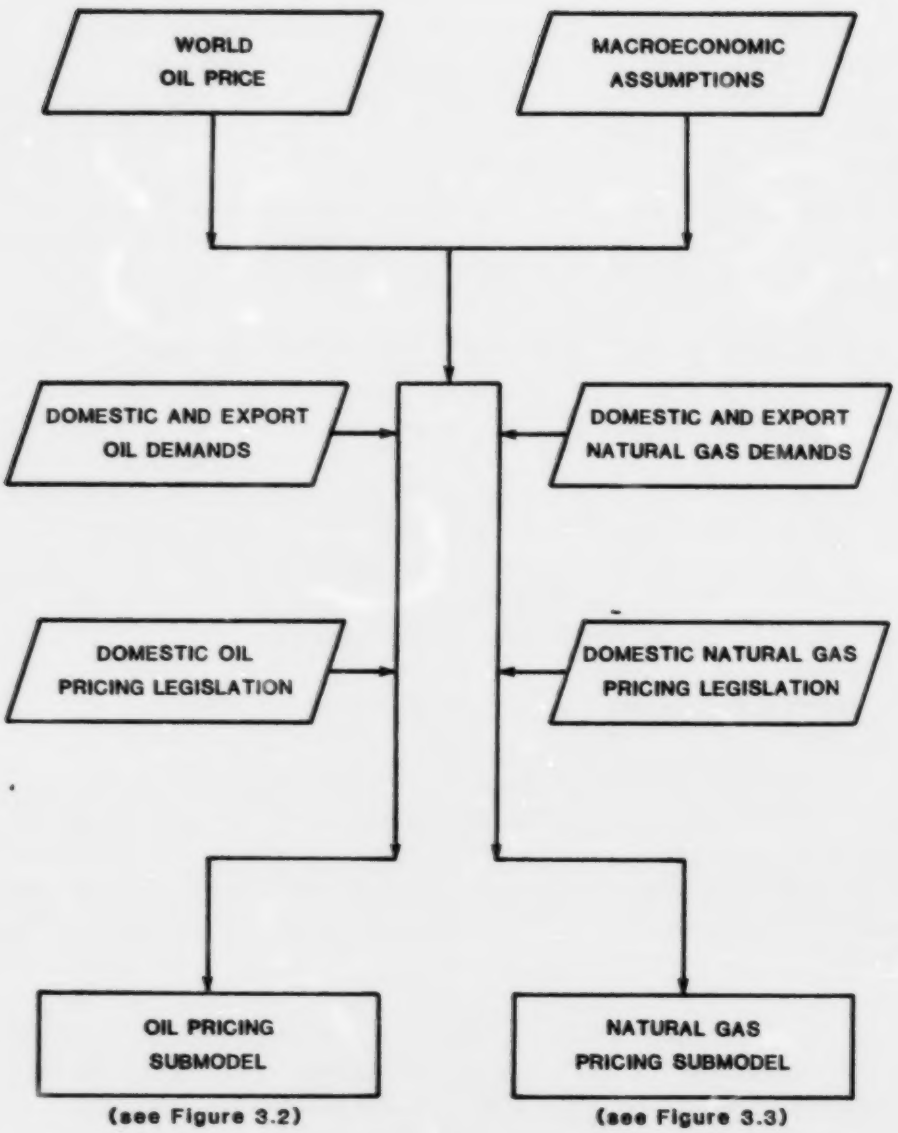


FIGURE 3.1: OVERVIEW OF COGPRICE

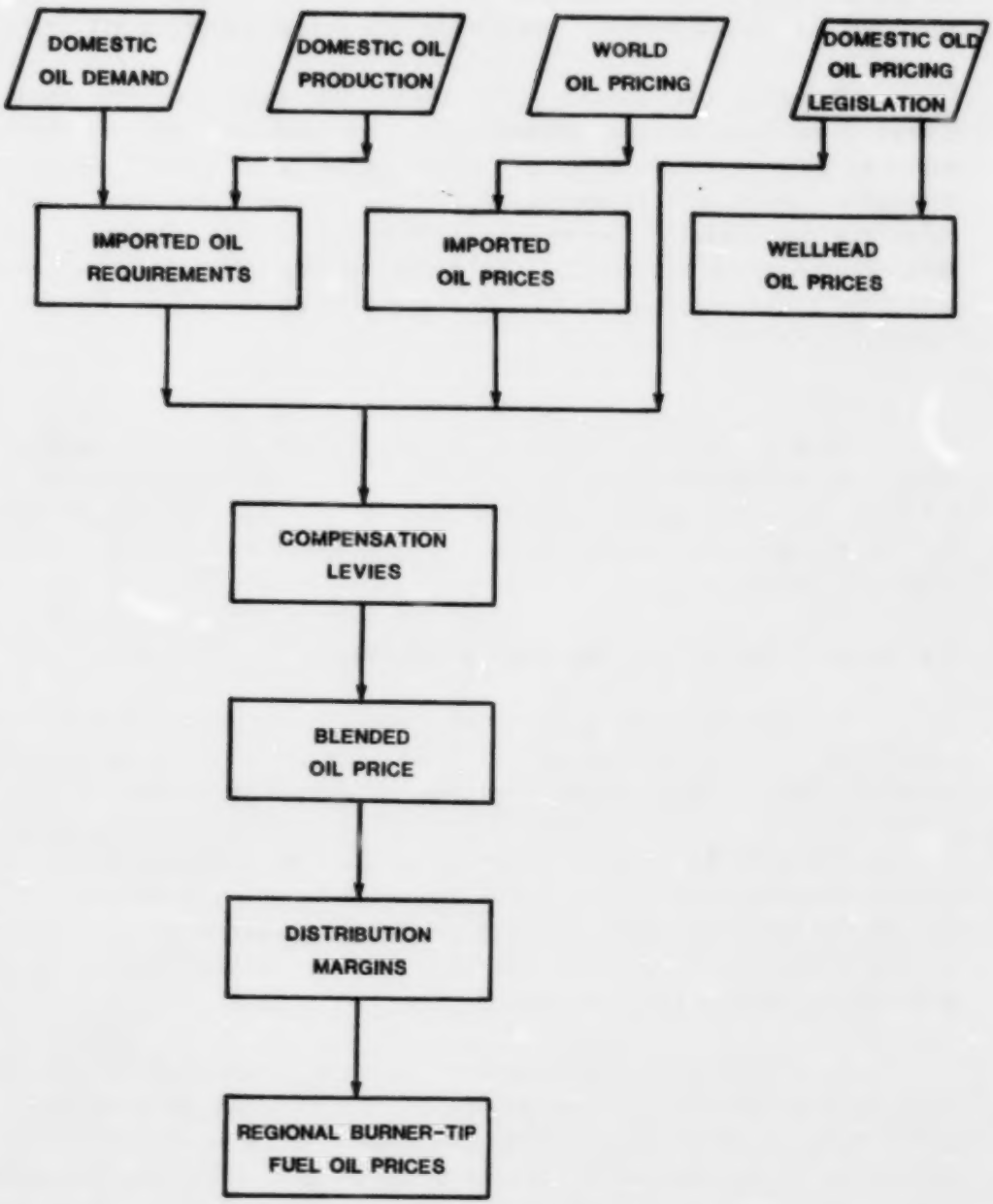


FIGURE 3.2: OIL PRICING SUBMODEL

fall below COOP, COOP will follow these imported prices down. If imported oil prices fall below COOP then begin to rise, COOP will rise to the lower of COOP's previous maximum or the actual imported oil price.

Domestic oil demand (from CREED) is combined with assumed domestic supplies of old conventional, new conventional, synthetic, enhanced recovery, and frontier oil together with export demand to determine import oil requirements. These volumes are then used to calculate compensation levies and a Montreal blended price of oil. This blended price represents a weighted average cost of oil. Transportation costs are removed to calculate blended prices at Vancouver, Edmonton, and Toronto as well.

From the blended price, differentials are applied to determine burner-tip prices for light and heavy fuel oil in British Columbia, the Prairies, Ontario, Quebec, and the Maritimes. The real growth rates in the blended and burner-tip prices are transferred to the demand models of CREED.

3.2 Natural Gas Pricing Sub-Model of COGPRICE

The natural gas submodel of COGPRICE (Figures 3.3 and 3.4) calculates wellhead and burner-tip natural gas prices on the basis of existing legislation and demand volumes calculated by CREED.

The Toronto city gate price of gas is proportional to the Toronto blended price of oil. The current proportion of 65 percent is assumed to continue. The city gate price is combined with the Canadian Ownership Special Charge and the Natural Gas and Gas Liquids Tax to determine a Toronto wholesale price.

The Alberta wholesale prices for the industrial/utility and residential/commercial sectors are based on a discount from the Alberta border price. The British Columbia wholesale price is determined as a percentage of the Vancouver blended price of oil. This B.C. percentage trends upward from 42 percent in 1983 to 65 percent in 1990, then remains constant.

Sectoral burner-tip prices are determined by adding distribution margins to the regional wholesale prices. The real growth rates of burner-tip prices are calculated by region by sector and passed to the sub-models of CREED.

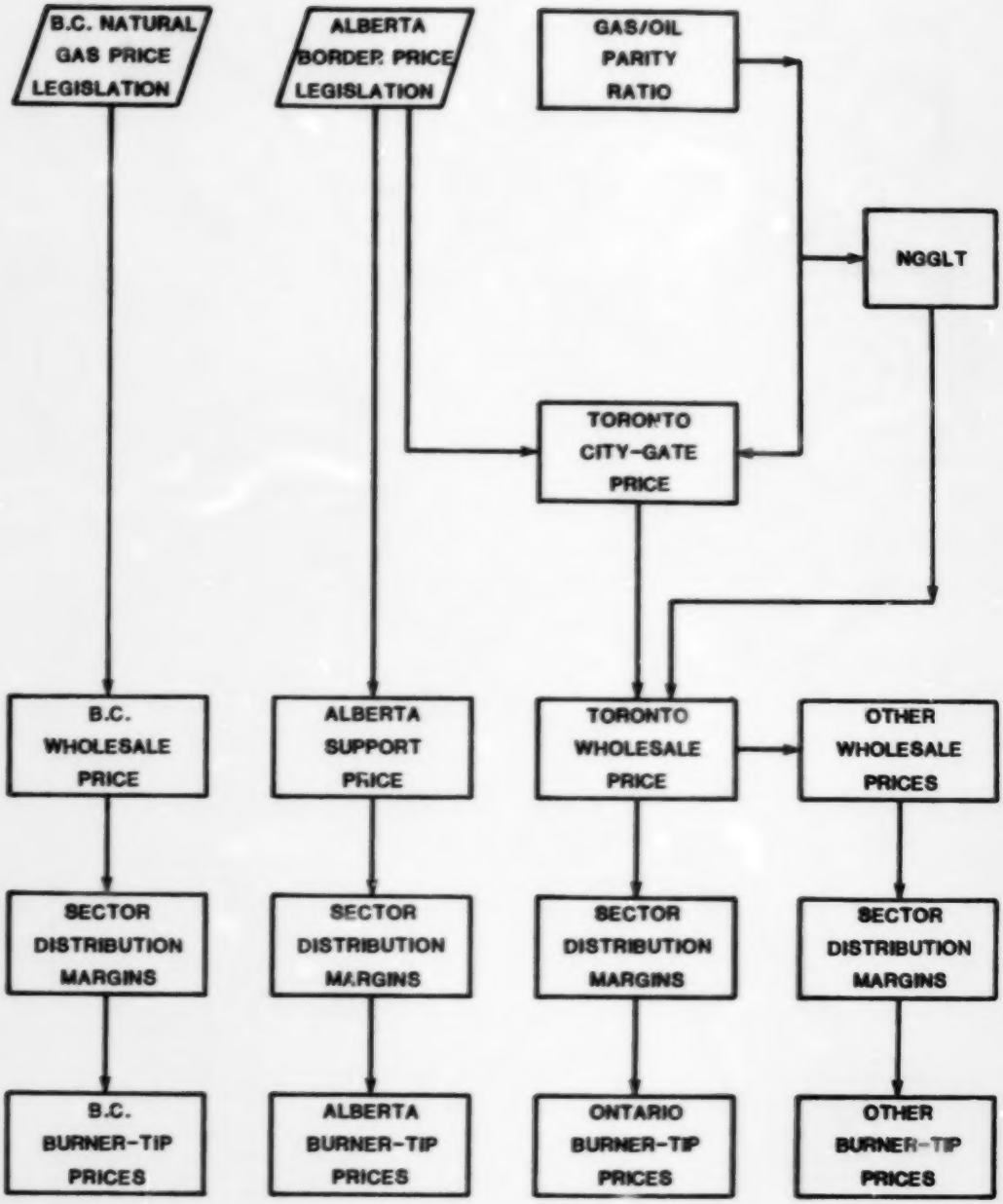


FIGURE 3.3: BURNER-TIP NATURAL GAS PRICING SUBMODEL

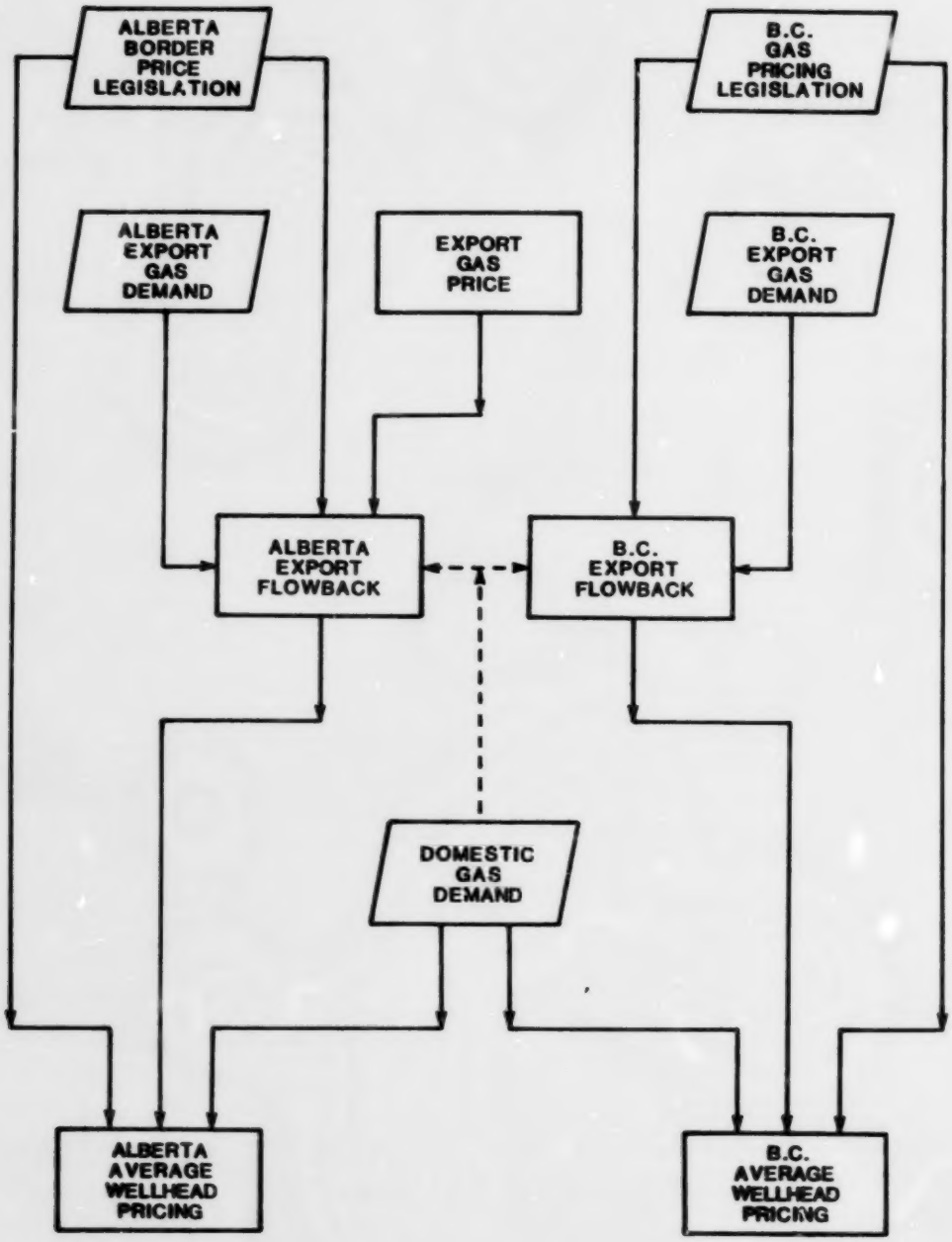


FIGURE 3.4: WELLHEAD NATURAL GAS PRICING DETAIL

The wellhead natural gas pricing section of COGPRICE (Figure 3.4) calculates wellhead prices for Alberta and British Columbia. Domestic demands are those calculated by CREED and export volumes are input exogenously.

The export border price is the Volume Related Incentive Price and does not include the recent flexibility to negotiate individual prices with individual customers. The export flowback is calculated on the basis of export prices, domestic and export demands, and Alberta and British Columbia pricing legislation. This flowback is then combined with domestic gas demand and legislation to calculate average wellhead prices.

3.3 Key Relationships in COGPRICE

The price of Saudi Light crude and the COOP pricing formula are the two key factors driving domestic burner-tip oil prices in COGPRICE. Domestic supply assumptions are important because they influence the levels of compensation levies, imported oil requirements, and the blended price of oil. The rate of inflation (relative to the rate of increase in world oil prices) and the exchange rate also impact domestic oil prices through the import price.

The world oil price influences natural gas prices through the Toronto blended oil price. This price and the 65 percent parity ratio are assumed to drive gas pricing throughout the forecast. These assumptions can be easily modified.

Wellhead gas prices are netbacks from the Alberta border.

3.4 Strengths

COGPRICE has the following strengths:

- COGPRICE is a complete representation of oil and gas pricing in Canada,
- the model contains a demand feedback mechanism to iterate toward a blended oil price that reflects changes in import and domestic oil quantities,
- the model fully reflects oil quality differentials, transportation costs, and pricing policy,
- the model allows easy sensitivity analysis, and

- the software provides goal-seeking capabilities (i.e., the ability to set the value of a target variable, then allow the model to determine the values of variables involved in the calculation of the target variable).

From the above analysis, it can be seen that COGPRICE permits the user to examine the burner-tip and wellhead pricing implications of a wide variety of policy issues. The complete integration of pricing rules and the goal-seeking software capability provide the ability to quickly determine the impact of a specified change. If a consistent set of exogenous macroeconomic and demand assumptions is input, COGPRICE can be used as a stand-alone model.

3.5 Weaknesses

CERI's use of COGPRICE has revealed the following weaknesses:

- new natural gas export pricing rules cannot be easily reflected in the model due to uncertainties regarding negotiated prices and the questions or regional differences;
- TCPL transportation cost of service, utility distribution margins and domestic oil supply are exogenous,
- the current model code and input data are costly and time-consuming to update and verify,
- COGPRICE was not originally designed to drive CREED and contains code that is not required as part of the CERI energy modelling system.

The exogenous nature of export natural gas demands and domestic oil supplies in COGPRICE places the burden on the user to input values consistent with macroeconomic assumptions and world oil pricing assumptions. The links between oil pricing policy and supply are not endogenous to the model.

Additional time would permit removal of some of the model code not strictly required to drive CREED. This could be replaced by improved calculations for TCPL tolls and utility distribution margins for natural gas. A separate model has been written to calculate the TCPL tolls, but has not been integrated with COGPRICE.

4. ILLUSTRATIVE FORECAST

This section presents the results of an illustrative forecast developed to demonstrate the forecasting properties of the model. These results are not intended to represent CERI's view of the future and should not be used or quoted as such.

4.1 Macroeconomic Assumptions

This illustrative forecast is based on a Saudi Light price of crude that holds at $29.00 U.S./bbl for 1984, remains flat in real terms from 1985-1990, then grows at one percent above inflation. Inflation is set at 5.5 percent for 1984, 6.0 percent per year for 1985-1990, then 5.5 percent per year thereafter.

Real domestic product is assumed to grow 3.8 percent in 1984, 0.6 percent in 1985, then an annual average of 3.0 percent through 1990, and 2.6 percent thereafter. Regional details are presented in Table 4.1. The short-term forecast (1983-1985) is based on figures supplied by the Conference Board of Canada (April 1984 projections). The medium and long-term figures are a CERI forecast.

Households are projected to grow at an average annual rate of 1.55 percent in 1984, trending down to 1.3 percent by 1990 and 0.95 percent by 2000. These figures are based on Statistics Canada projections. Regional detail is provided in Table 4.2.

4.2 Forecast

Total secondary energy demand (excluding coal) is presented by sector in Figure 4.1. In the long run, energy demand grows at an average annual rate of 1.5 percent or less. Energy demand grows at a rate about 1.5 percentage points below RDP growth in the short and medium term and about 1.2 percentage points below RDP growth in the long run. This suggests a long-term trend toward energy conservation as real energy prices rise.

The sectoral breakdown shows the residential/commercial share of energy use rising from 32 percent in 1984 to 35 percent by the end of the forecast. This reflects continuing growth in the service and government sectors relative to the rest of the economy. The industrial

TABLE 4.1

PROJECTED REAL DOMESTIC PRODUCTION

Year	Atlantic	Quebec	Ontario	Manitoba	Saskatch-ewan	Alberta	British Columbia	Canada
REAL DOMESTIC PRODUCT ($1971)								
1983	7,120	27,304	47,187	4,650	4,460	13,492	14,021	118,235
1984	7,370	28,424	49,452	4,859	4,567	13,411	14,119	122,202
1985	7,451	28,537	49,452	4,889	4,635	13,532	14,373	122,869
1990	8,637	33,083	57,329	5,397	5,244	15,687	17,071	142,448
1995	9,773	37,430	64,862	5,814	5,790	18,185	19,790	161,645
2000	11,057	42,349	73,386	6,264	6,393	21,082	22,942	183,471
2010	14,153	54,210	93,940	7,269	7,793	28,332	30,833	236,530
ANNUAL GROWTH RATES (PERCENT)								
1984	3.51	4.10	4.80	4.50	2.40	-0.60	0.70	3.36
1985	1.10	0.40	0.00	0.60	1.50	0.90	1.80	0.55
1990	3.00	3.00	3.00	2.00	2.50	3.00	3.50	3.00
1995	2.50	2.50	2.50	1.50	2.00	3.00	3.00	2.56
2000	2.50	2.50	2.50	1.50	2.00	3.00	3.00	2.57
2010	2.50	2.50	2.50	1.50	2.00	3.00	3.00	2.57

TABLE 4.2

HOUSEHOLD PROJECTIONS

Year	Atlantic	Quebec	Ontario	Manitoba	Saskatch-ewan	Alberta	British Columbia	Canada
HOUSEHOLDS (thousands)								
1983	668	2,241	3,078	361	335	773	1,005	8,461
1984	673	2,268	3,131	366	338	786	1,027	8,592
1985	677	2,289	3,182	371	342	802	1,048	8,710
1990	697	2,397	3,427	391	357	871	1,151	9,291
1995	712	2,470	3,616	400	366	937	1,240	9,744
2000	729	2,545	3,801	411	376	1,010	1,336	10,207
2010	762	2,702	4,192	432	395	1,173	1,550	11,121
ANNUAL GROWTH RATES (PERCENT)								
1984	0.75	1.18	1.74	1.50	1.00	2.00	2.20	1.55
1985	0.60	0.96	1.60	1.20	1.00	1.70	2.00	1.37
1990	0.57	0.92	1.50	1.06	0.90	1.66	1.90	1.30
1995	0.45	0.60	1.08	0.50	0.50	1.50	1.50	0.96
2000	0.45	0.60	1.00	0.50	0.50	1.50	1.50	0.95
2010	0.45	0.60	1.00	0.50	0.50	1.50	1.50	0.95

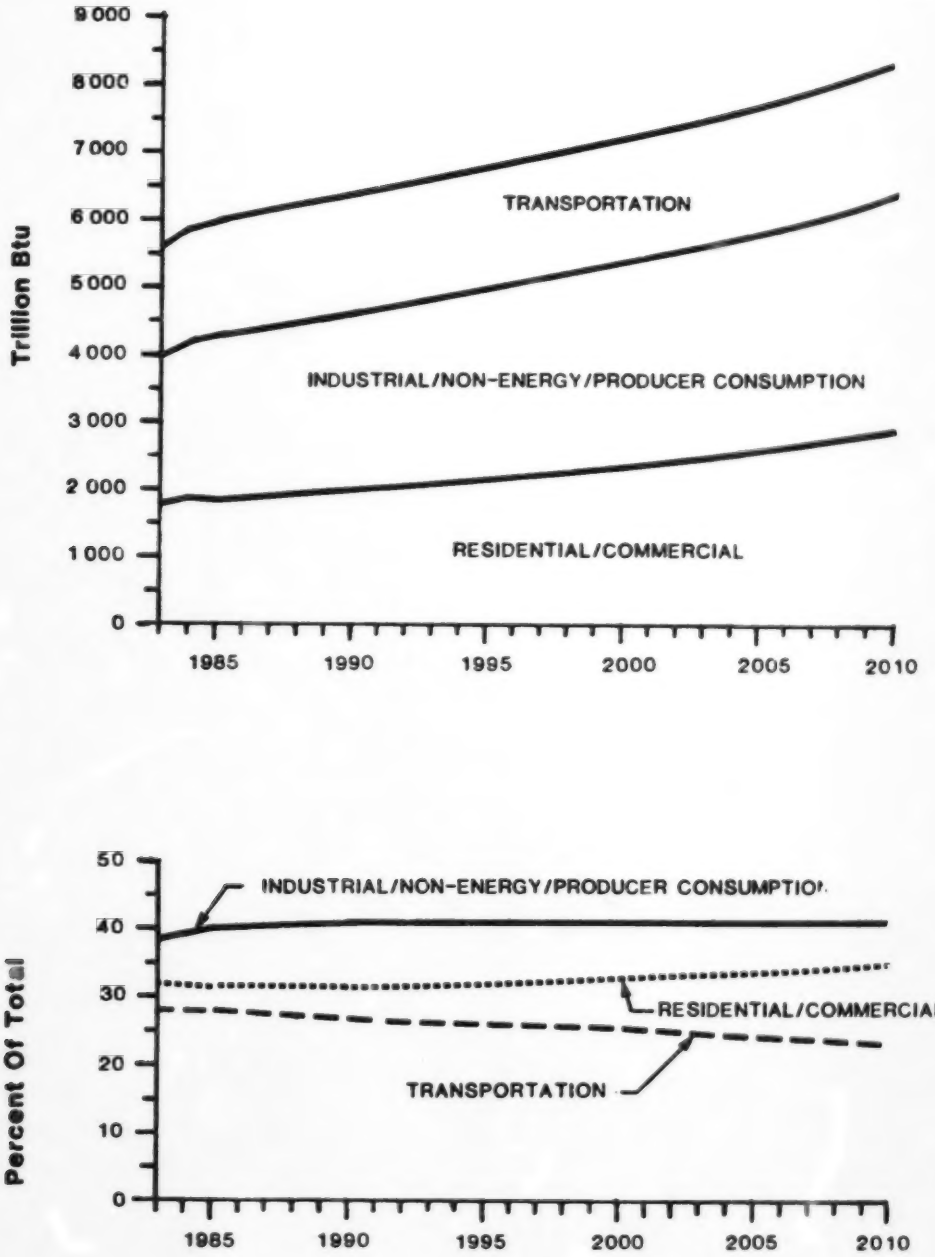


FIGURE 4.1: TOTAL SECONDARY ENERGY DEMAND BY SECTOR

sector's share of total energy consumption continues to grow as well, although at a slower rate (from 39.6 percent in 1989 to 41.6 percent in 2010). The transportation sector's share declines from 28.3 percent in 1984 to 23.4 percent in 2010. This decline reflects a continuing strong conservation trend.

Secondary energy demands by fuel are presented in Figure 4.2. In the 1984-1990 period, demands for all fuels increase in absolute terms. Natural gas shows the strongest growth (over 3.0 percent per year on average), indicating continued penetration into Ontario and Quebec markets. By 1990, natural gas market share has increased to 31.9 percent from 28.6 percent in 1984. Electricity has gained only 0.5 percentage points over the same period with oil's share declining 3.9 percent. This shift occurs even though electricity prices are not rising as fast as natural gas prices.

In the long term (1990-2010), continued off-oil fuel switching leads to a gradual decline in the level of oil demand with a continued decrease in market share. Natural gas demand grows at a slightly faster rate than electricity over the period, despite a narrowing of price differentials. The demand growth reflects the regional pattern of market penetration (particularly in Western Canada) as well as the sectoral shift toward the residential/commercial sector in regions where natural gas has penetrated those markets.

The effects of continuing energy conservation are represented in Table 4.3. Residential energy use per household shows a steady downward trend throughout the forecast, although the rate of decrease slows in the later years. Commercial energy use per dollar RDP also decreases sharply in the early years, but has begun to increase slightly by the year 2000. This movement in energy use ratios suggests that, in the residential and commercial sectors, the effects of the energy price shocks of the late 1980s have been worked off and a more gradual long-run trend established by the 1990s.

In the industrial sector, energy use per dollar RDP increases in the short term (1984-1987). By 1990, continued conservation effects of real price increases combine with more stable economic growth trends to show a net decrease in energy use per dollar RDP. The more sustained impact of price increases in this sector is largely due to the longer price lags in the Ontario industrial sector equations.

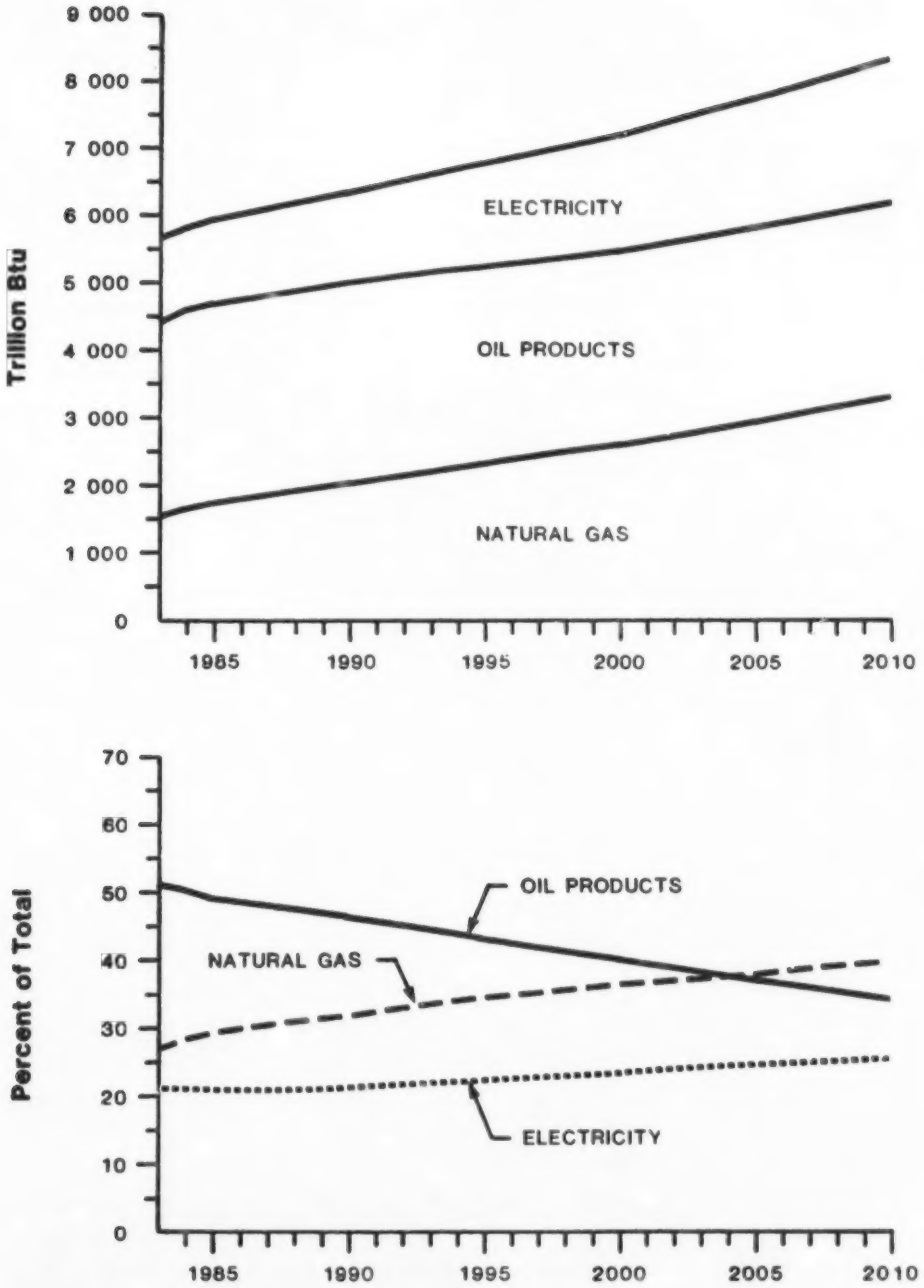


FIGURE 4.2: TOTAL SECONDARY ENERGY DEMAND BY FUEL

TABLE 4.3

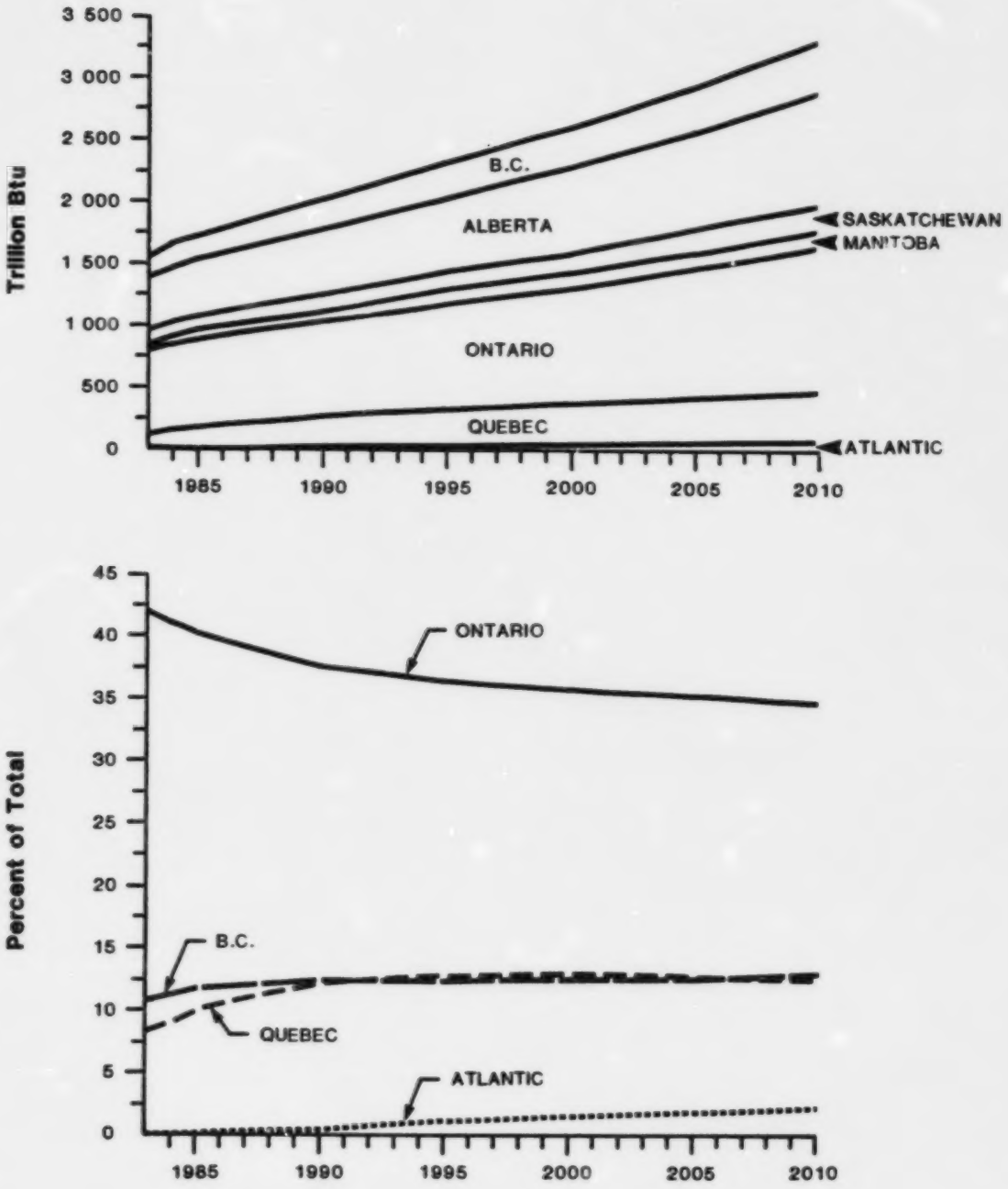
ENERGY USE RATIOS

Year	Residential Energy Demand/ Household	Commercial Energy Demand/ $ Commercial RDP	Industrial Energy Demand/ $ Industrial RDP	All Sectors Energy Demand/ $ RDP
1983	115.86	11.22	33.91	47.96
1984	119.92	10.90	34.99	47.95
1985	119.26	10.66	36.76	48.40
1990	116.88	9.99	37.36	44.81
1995	115.06	9.98	36.24	41.88
2000	113.84	10.06	34.87	39.27
2010	112.97	10.46	33.11	35.30
ANNUAL GROWTH RATES (PERCENT)				
1984	3.50	-2.85	3.18	-0.02
1985	-0.55	-2.20	5.06	0.94
1990	-0.40	-1.29	0.32	-1.53
1995	-0.31	-0.02	-0.61	-1.34
2000	-0.21	0.16	-0.77	-1.28
2010	-0.15	0.39	-0.52	-1.06

4.3 Regional Factors

The regional distribution of total energy demand implied by the reference forecast does not change significantly through time. This is largely due to the stability of the regional distribution assumed for RDP. Some interregional trends in household formation result in a slight narrowing of differences in income per household across regions. This results in a small shift in residential energy demand away from Ontario into Quebec and the Atlantic.

A more interesting story emerges in the regional distribution of individual fuel demands. Ontario's importance as a consumer of natural gas declines over the forecast period, while Quebec's importance increases (see Figure 4.3). This reflects both increased market penetration in the Quebec and Atlantic markets as well as a gradual, long-term increase in the already high gas penetration in the producing provinces. In Ontario, competition with electricity is an important factor in limiting long-run growth in natural gas demand. In 1983, 30.6 percent of all secondary electricity demand originates in Ontario. By the end of the forecast, that percentage has risen to 32.1 percent. In Quebec as well, competition between electricity and natural gas is an important factor, particularly in the residential and commercial markets. In Quebec, however, natural gas has been penetrating a relatively new market. This penetration is not expected to reduce the level of electricity demand, but could well dampen its rate of growth.



NOTE: Shares for Alberta, Saskatchewan, and Manitoba are constant over the period.

FIGURE 4.3: REGIONAL DISTRIBUTION OF NATURAL GAS DEMAND

October 1984

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Presentations by Staff (available upon request)

83-1 Household Energy Costs: Recent Developments and Options for the Future. G. E. Angevine. Notes for Remarks at the "New Neighbourhood Forum," sponsored by the Ontario Ministry of Housing and Municipal Affairs, Toronto, January 31, 1983.

83-2 Net Regional and National Benefits of Canadian Electricity Exports. Gordon S. Gislason, Ellen F. Battle, and Gordon W. Douglas. Paper presented to the Canadian Electrical Association Generation System Planning and Operation Subsection, Vancouver, March 21, 1983.

83-3 Economic and Financial Implications of Lower Oil Prices. Walter Haessel. Paper presented at a conference on The Impact of Lower Oil Prices, sponsored by Data Resources of Canada, Sheraton Centre, Toronto, April 14, 1983

83-4 Energy Pricing in the World and Canada. James A. MacMillan. Paper presented to the Canadian Chapter of the International Association of Energy Economists, Toronto, May 20, 1983

83-5 Canadian Energy Issues and Outlook. Douglas J. Haughey. Paper presented to the Institute of Internal Auditors, Calgary, October 18, 1983.

84-1 The CANREM Model: Model Structure, User Experience and Potential Applications. Gordon W. Douglas, Gordon S. Gislason and Ellen F. Battle. Presentation to the Canadian Electrical Association Meetings, Edmonton, March 15, 1984.

Proceedings

International Gas Markets Conference. Proceedings of a Conference held on September 26, 1983, Calgary, Alberta. Edited by Shane Streifel. (Price $45.00, 247 pages) ISBN 0-920522-33-5.

Annual Report

Board of Directors' Report for the Year Ended March 31, 1984. ISBN 0-920522-32-7.